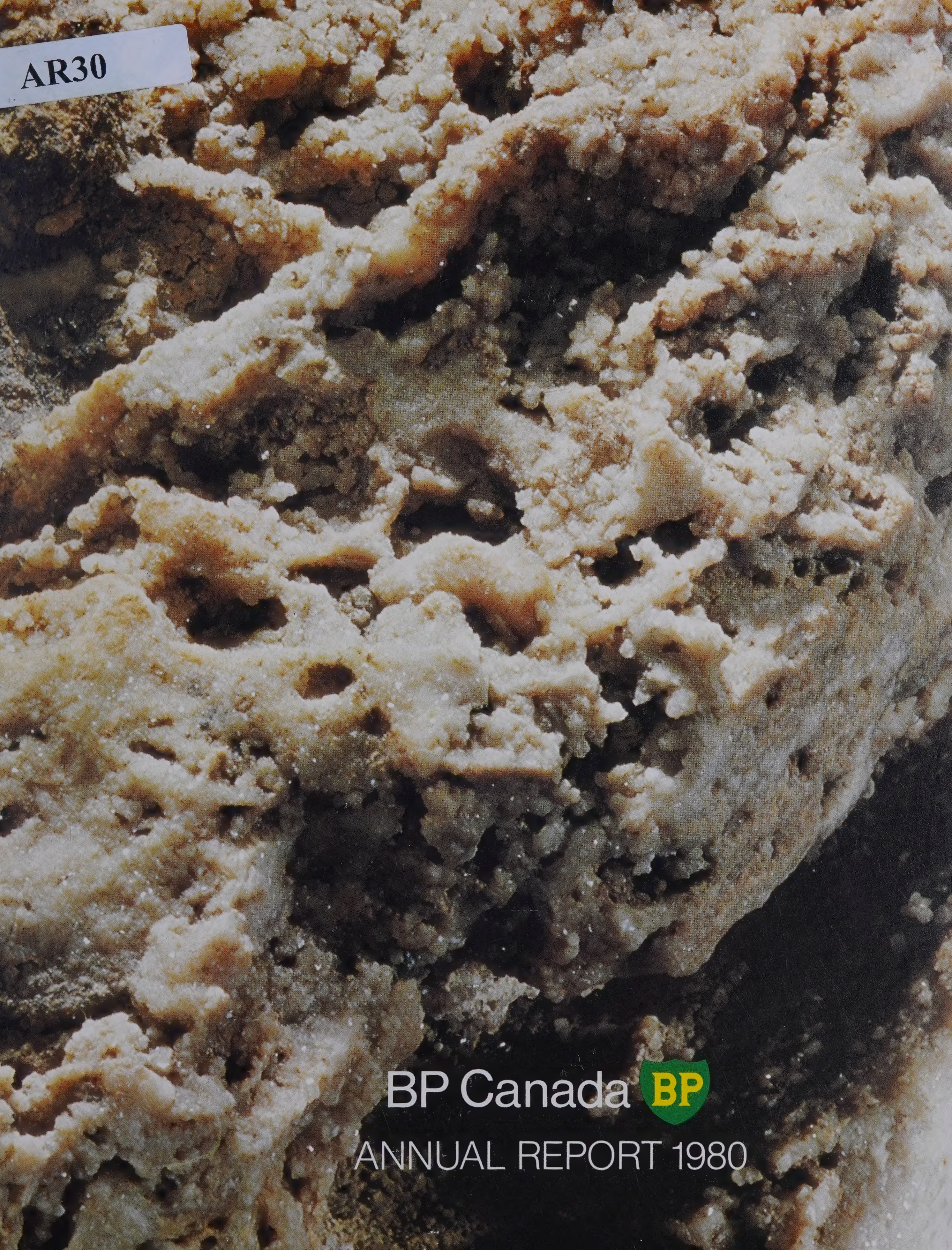

BP Canada

ANNUAL REPORT 1980

About the Cover

This oil-saturated section of rock, shown in enlargement on the front cover, was recovered from a well drilled by BP in the Ponoka district of south-central Alberta.

Before the Alberta production cutback which took effect March 1, 1981, conventional crude oil from the Western provinces accounted for 76 per cent of Canadian consumption. Another 7 per cent was supplied by the two oil sands plants operating in Alberta. The remaining 17 per cent was provided by imports, largely from members of the Organization of Petroleum Exporting Countries (OPEC).

To the extent that domestic oil supply falls short of demand, Canada will continue to be dependent upon imports from insecure sources, with a consequent adverse effect on its balance of payments.

Canada's production of conventional crude oil is declining. More is being produced than new discoveries and improved recovery techniques can add. Development of additional oil sands plants — which take a minimum of six years to come on stream — is held up by the dispute between the governments of Alberta and Canada. Frontier production, from the fields discovered in the Beaufort Sea and off the coast of Newfoundland, is still at least five years away.

With domestic production declining, the only way to diminish the volume of imported oil in the next few years will be to reduce demand — by conservation and by the substitution of other energy sources for oil. At the same time, maximum effort must be devoted to finding and developing new domestic oil sources for Canada's future needs.

The federal government is encouraging conservation and substitution, but the effectiveness of its efforts will be lessened by failure fully to utilize the lever of price to achieve its objectives. As long as it continues to hold down the price paid to domestic oil producers and to subsidize imports costing twice as much, consumers will lack the prime incentive to curtail consumption.

Over the longer term, given an appropriate investment climate, Canada undoubtedly has the resource base to increase domestic oil production to the point where imports would no longer be required — the elusive goal of oil sufficiency.

In his Report to the Shareholders on page 2, the Chairman explains why the National Energy Program as presently formulated is unlikely to achieve this objective, and puts forward alternative proposals for its attainment.

Highlights for the year 1980

with 1979 figures shown on a comparable basis

		1980	1979	% change
		(thousands of $ unless otherwise stated)		
Financial	Net income for the year	**104,304**	66,989	+55.7
	Net income per share (dollars)	**4.89**	3.16	+54.7
	Return on average capital employed (%)	**17.33**	13.02	+33.1
	Shareholders' equity at end of year	**501,511**	418,315	+19.9
	Revenue – sales and services	**1,258,530**	999,380	+25.9
	Total funds derived from operations	**163,355**	115,953	+40.9
	Expenditures on property, plant and equipment, and exploration	**117,964**	98,523	+19.7
Operating	(thousands of cubic metres per day unless otherwise stated)			
	Refined product sales	**17.4** (109,226 barrels)	17.6 (110,874 barrels)	−1.5
	Crude oil processed at refineries	**17.9** (112,591 barrels)	18.2 (114,478 barrels)	−1.6
	Gross sales of crude oil and natural gas liquids	**4.1** (26,085 barrels)	3.9 (24,335 barrels)	+7.2
	Gross sales of natural gas (million cubic metres per day)	**2.7** (94,256 thousand cubic feet)	3.1 (110,492 thousand cubic feet)	−14.7

The Company's capital stock is listed for trading on the Montreal, Toronto and Vancouver stock exchanges. Cash dividends paid and the high and low prices of the Company's common shares on the Toronto Stock Exchange for the last two years are shown in the table.

	1980			1979		
	Dividends paid	High	Low	Dividends paid	High	Low
First quarter	**25¢**	**$57**	**$36**	13¢	$25¼	$20¼
Second quarter	**25**	**46½**	**37½**	13	29½	22⅛
Third quarter	**25**	**49¾**	**43¼**	16	42	25¾
Fourth quarter	**30**	**47¼**	**35**	16	41¾	32
Year	**$1.05**	**$57**	**$35**	58¢	$42	$20¼

Unless otherwise stated, all dollar amounts shown in this report are Canadian.

The Annual Meeting of Shareholders of BP Canada Inc. will be held at 11:30 a.m., Friday, 24th April, 1981 at the Company's offices on the 57th floor, First Canadian Place, Toronto

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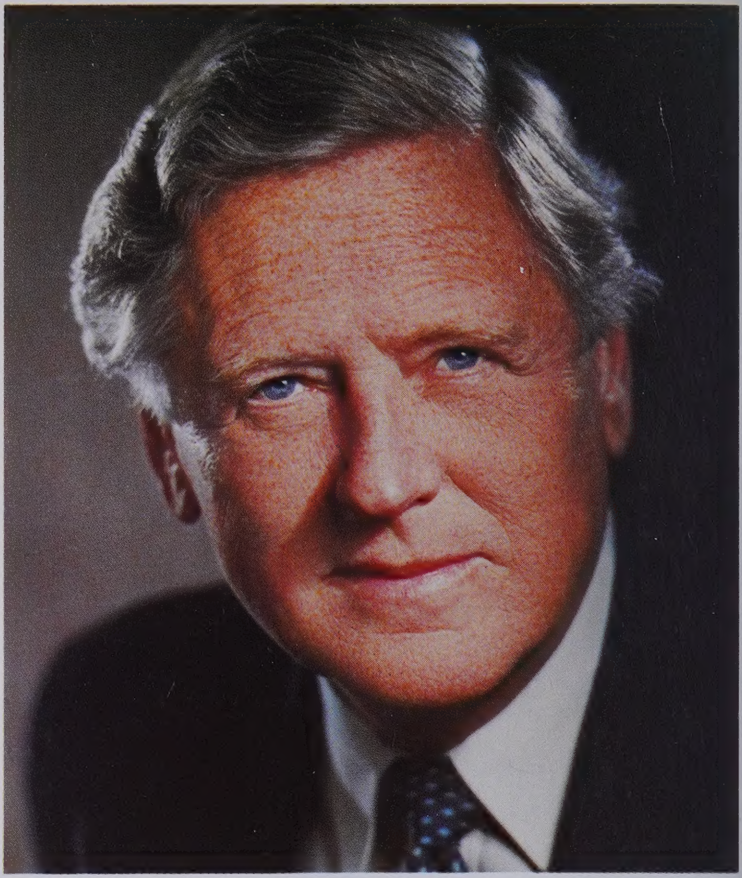
Chairman's Report to the Shareholders



Improved margins in the refining and marketing sector combined with slightly higher earnings from natural resources resulted in the net income of the Company being some 56 per cent higher than in 1979 at $104.3 million.

This was achieved on net sales revenues of $1.12 billion, and was equivalent to 9.3 cents on the sales dollar. The rate of return on capital employed in 1980, on a historical cost basis, increased to 17.3 per cent, compared with 13.0 per cent in 1979.

Unfortunately, I have to warn you that, as a result of the cutbacks in oil production imposed by the Alberta government and the Petroleum and Gas Revenue Tax on production introduced in the federal budget last October, earnings from the natural resources sector will be seriously diminished this year. Indications are that the Company's cash flow from oil and gas operations will be reduced by some $23.0 million, or 24 per cent, from the level anticipated prior to the budget.

Also, despite the fact that BP Canada has one of the highest proportions of public ownership among the international oil companies operating in Canada – 36 per cent – we shall, as things stand, be entitled to none of the incentive grants proposed in the National Energy Program (NEP) on provincial lands to compensate for the phasing-out of depletion allowances, and to only the standard 25 per cent of qualifying exploration expenditures on the high-risk Canada lands. Whilst we are urgently examining possible means by which the adverse effect of this deliberate discrimination may be minimized, it is a complex matter on which it may be unwise to reach specific conclusions until the precise rules have been established.

As a result of these and other aspects of the NEP, we have judged it appropriate to restrict our 1981 capital spending program for oil and gas exploration and development to $92.0 million – some $20 million less than had been planned prior to the October budget. In 1980, BP Canada invested a total of $118.0 million (with natural resources accounting for $97.8 million).

The chief factor holding down earnings from the natural resources sector in 1980 was the weak demand for natural gas, both domestically and for export to the United States, the latter largely due to the unrealistically high export price imposed by Canada. This more than offset the benefit of higher gas prices. It was particularly disappointing that the extensive Sukunka-Bullmoose gas fields in British Columbia, which only came into production in the fall of 1979, were shut in for a large part of the year. On the other hand, production of crude oil and natural gas liquids was 7.2 per cent higher than in 1979, with prices rising by 15.1 per cent.

Crude oil supply again posed difficulties. The Iraq-Iran war removed well over three million barrels per day from the international market and, as a consequence, the Organization of Petroleum Exporting Countries (OPEC) was able to increase prices on no less than three occasions during the year. By early 1981, the cost of a barrel of light foreign crude delivered to eastern Canada stood at about $45 – some 40 per cent higher than in December 1979.

Prices for Canadian crude oil rose by $3 per barrel in 1980 and by another $1 on January 1, 1981, raising the wellhead price of Alberta crude to $17.75 per barrel, less than half the price of imported crude.

However, despite the tight international crude oil supply situation in the early part of the year, BP Canada was able to maintain deliveries to its refineries by obtaining additional quantities of western crude oil, some of which was obtained through exchanges with U.S. companies. With the first of the three announced cutbacks in oil production now being imposed by the Alberta government, eastern Canada refiners are having to import additional volumes of foreign crude oil to make good this shortfall in domestic supplies. In current market conditions, this is not expected to give rise to shortages in eastern Canada, but it will certainly place a further unneeded burden on Canada's balance of payments.

The proposed National Energy Program which, overnight, has changed many of the rules of the game, presents the industry and the people of Canada with a whole range of problems, most of which are of Canada's own making; and, interestingly enough, it appears to have virtually no support amongst Canada's business community. Its stated basic objectives are threefold:

- security of supply and ultimate independence from the world oil market;
- opportunity for all Canadians to participate in the energy industry, particularly oil and gas, and to share in the benefits of its expansion;
- fairness, with a pricing and revenue-sharing regime which recognizes the needs and rights of all Canadians.

There are few, including the oil industry, who would quarrel with these objectives. The oil industry, however, and many informed observers outside it, seriously question the means chosen for their achievement.

Canada is blessed with an abundance of energy resources. The problem is that proven reserves of one of these resources, oil, have been declining over the past 12 years, and new reserves are becoming ever more difficult and costly to find and develop. Time is also a crucial factor, with lead times of many years needed to bring into production a new offshore field or an oil sands plant. To transform these resources in the ground into usable oil will require an unprecedented effort in terms of investment, manpower, managerial skills and technological know-how, and one might suppose that any program which has among its principal objectives the achievement of oil self-sufficiency should first and foremost address itself to the removal of barriers which prevent their full and speedy mobilization.

Instead, the NEP has resulted in a political impasse between Ottawa and the governments of the producing provinces,

with work held up in Alberta on two urgently-needed oil sands plants; an estimated reduction of some 30 per cent in the cash which will be generated from conventional oil and gas production in Alberta in 1981 and which is urgently needed for new investment; a system of incentive grants for work on Canada lands which deliberately discriminates against the international oil companies who are best equipped to do the job; and a general loss of investor confidence resulting from the provisions under which Petro-Canada can obtain, free of any cost, a 25 per cent interest in all commercial discoveries on Canada lands. The NEP hopes that oil sufficiency will be achieved by 1990 by reducing demand through conservation, by exhortation and by substitution, rather than by maximising production. To the best of my knowledge, no one shares this expectation with the authors of the program, especially since they have elected not to use the full force of the price mechanism to promote oil conservation.

In fact, to any dispassionate observer oil self-sufficiency appears to have the lowest priority among the NEP's objectives – the real emphasis seems to be on increasing the federal government's ownership and control of the industry and its share of revenues. Neither will add a single barrel to Canada's oil supply, and you may well wonder why any government should think it can run an industry as complex as the oil industry better than those who have spent their lives in it.

In short, the federal budget and the NEP, as proposed, have severely reduced the capacity of the industry to earn the profits needed to maintain the momentum of oil and gas exploration and development, as well as removing much of the incentive to invest in these risky ventures. As a consequence, not only will Canada's drive towards self-sufficiency be slowed or even halted, but the Canadian economy will lack the stimulus which would have been provided by billions of dollars of oil-related investment. Further, it will be burdened by additional outflows of currency to import foreign crude oil at ever increasing prices – oil which may not even be available.

At the root of the problem is the federal government's continued unwillingness to move quickly towards world levels of crude oil prices. Under the NEP, Canadian crude oil prices will rise by only $2 per barrel annually until the end of 1983. If, instead, prices increased each year by, say, $4 or $5 per barrel, increased revenues would flow to both levels of government and the industry could have the increased cash flow needed to continue its efforts towards finding and developing new Canadian oil supplies.

The second objective of the National Energy Program, the "Canadianization" of the petroleum industry, could be achieved much more simply and efficiently than under the Petroleum Monitoring Agency's complex and unworkable route by encouraging the international companies to make more of their shares available to the Canadian public, and then, through tax incentives, making it attractive for Canadians to buy and hold these shares.

The NEP paints a picture of international oil companies which bears little resemblance to reality and ignores their tremendous contribution to the development of Canada. It implies, but fails to demonstrate, that, without massive government intervention, they will, in some unspecified way, cease to serve Canada well in the future. It chooses to ignore the fact that governments already have the power to control by legislation and regulation almost every facet of the petroleum industry. To suggest that the "correct" degree of control of the industry can only be achieved by overt discrimination against companies with significant foreign shareholdings and that large amounts of Canada's capital resources are best employed in acquiring one or more of these companies is totally unproven.

If Canada is to reap the full benefit of the natural resources with which she is so bountifully endowed, it is essential that the National Energy Program be substantially modified while there is still time. All its objectives can be achieved if the federal and provincial governments will settle their differences and the industry is allowed to earn, under a stable and fair set of rules, a return on investment commensurate with the risks.

At the time of writing, the seven-volume report by the Director of Investigation and Research, Combines Investigation Act, entitled The State of Competition in the Canadian Petroleum Industry, has just been released amidst a blaze of publicity and propaganda. While we have not yet had the opportunity to study it in detail, it is clear that:

- Even after eight years of investigation and an enormous expenditure of public and private funds, the Director has not felt able to justify embarking on a prosecution. One can, therefore, conclude that he believes he will be unable to prove any breaches of the law. This comes as no surprise so far as BP Canada is concerned. Our policy is clear: we operate at all times within the laws of Canada.
- Having failed to demonstrate illegal activities, the Government is now bent on putting on a "circus" for the benefit of the media and the public, which may run for several more years – at what cost to the economy and the taxpayer none can tell. The principal purpose will, doubtless, be to try to justify by propaganda and by "trial" in the media the federal government's already well-demonstrated xenophobic prejudices against one of Canada's vital and most successful industries.

The federal budget and the NEP were published towards the end of what had already been an eventful year for the Company and its employees. We successfully completed the move of our executive office from Montreal to Toronto with a minimum of disruption and quickly settled into our new headquarters in First Canadian Place, where we shall be holding our 1981 Annual Meeting of Shareholders. Some 120 employees and their families were involved in the move and I would like to thank them – and, indeed, all the 3,800 BP Canada men and women – for their continued devotion and loyalty.

It was with the greatest sadness that we learned of the death of Mr. R. M. Fowler early in July. He was Chairman from December 1971 to April 1977 and at the time of his death was Honorary Chairman. Although he had had no experience of the industry at the time of his election as a director in 1971, he led the board with great style and distinction through most of the decade and was a wise and much sought-after counsellor. We send our deeply-felt sympathies to Mrs. Fowler and to the family.

Mr. P. J. Gillam will not be standing for re-election to the board at this year's Annual Meeting, having been reassigned to other duties by the British Petroleum Company.

Mr. W. A. L. Manson, President of BP North America Inc., has been nominated to fill this vacancy. Mr. Manson was previously a director of BP Canada from December 1975 to April 1978 and we welcome him back.

On your behalf, I would like to thank Mr. Gillam, whom we shall greatly miss, and all the directors for their services and for their invaluable support and advice over the past year.

D. F. Mitchell
Chairman
and Chief Executive Officer

March 5, 1981

Natural Resources

BP maintained an active and well-balanced program of exploration and development in 1980 and was particularly successful in discovering further reserves of natural gas.

At year end the Company's crude oil reserves were some 5.6 per cent lower than at the end of 1979, while reserves of natural gas were 0.9 per cent higher. Included in the oil reserves, as shown in the accompanying table, are some 1.8 million cubic metres in Saskatchewan. The taxes proposed in the October 1980 budget combined with the present provincial tax and royalty regime make the production of these reserves totally uneconomic. However, in the hope and belief that reason will shortly prevail, the Company is continuing to produce them despite an overall loss of up to 40 cents per barrel produced.

Increased production of crude oil and natural gas liquids, combined with higher prices, resulted in an increase of 23.7 per cent in the gross revenue, less royalties, from that sector. Despite a continuing decline in demand for natural gas, particularly in the export market, gross revenue, less royalties, from natural gas sales rose by 29.4 per cent because of higher prices. Overall, the contribution of natural resources activities to BP's after-tax income was slightly higher in 1980 than in 1979.

The average realization (after royalties) for crude oil and natural gas liquids rose to $55 per cubic metre in 1980, against $48; for natural gas to $54 per thousand cubic metres, against $36; and for sulphur to $41 per tonne, against $17.

The Company reinvested in further exploration and development ventures almost the entire cash flow derived from natural resources production.

Oil and Gas

BP's production of crude oil and natural gas liquids rose by 7.2 per cent to reach an average of 4,145 cubic metres per day in 1980. There was a significant increase in Alberta liftings, largely attributable to higher production from the Redwater field; this was offset in part, however, by a natural decline in production from British Columbia, Saskatchewan and some Alberta fields.

Production of natural gas, at an average of 2,670,000 cubic metres per day, was 14.7 per cent lower than in 1979 and significantly lower than contracted volumes, due largely to the very depressed state of the export market. Particularly affected were the Sukunka and Bullmoose fields in northeastern British Columbia, which were shut-in for ten months and six months respectively.

As in some previous years, purchasers generally were unable to accept all the gas they had contracted to buy. During 1980 the Company received a net amount of $8.4 million in respect of gas paid for but not taken.

The demand for sulphur continued strong in both Canadian and export markets. BP sold 18 per cent more sulphur than in 1979, at 229 tonnes per day, against 194 tonnes.

During 1980 BP participated in the drilling of 75 exploratory wells, which resulted in 48 gas discoveries and 2 oil discoveries. The Company also participated in 153 development wells, which resulted in 41 gas wells and 90 oil wells.

Although BP's land holdings decreased somewhat during 1980, the Company participated successfully in several Crown sales, resulting in the acquisition of 30,923 net hectares in Alberta and British Columbia at an average cost of $673.13 per hectare.

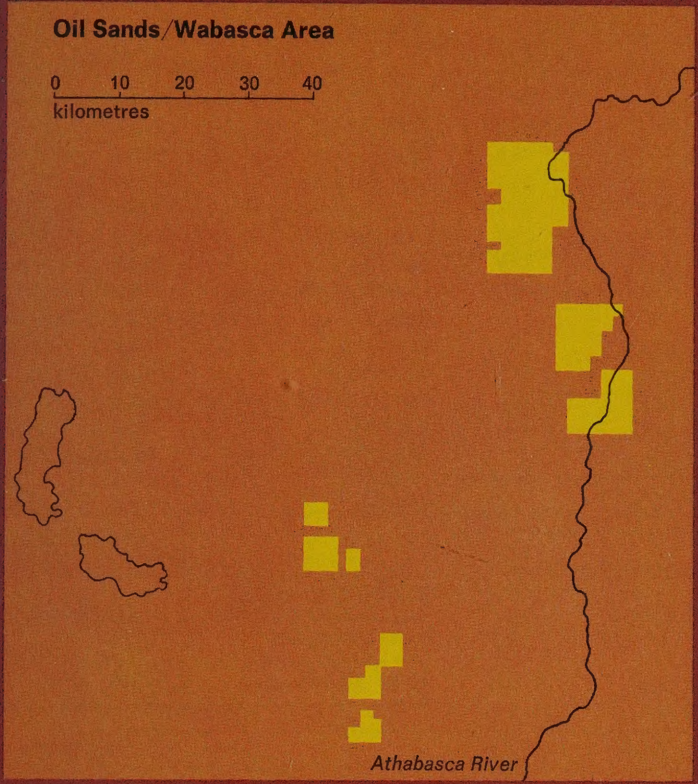
Alberta

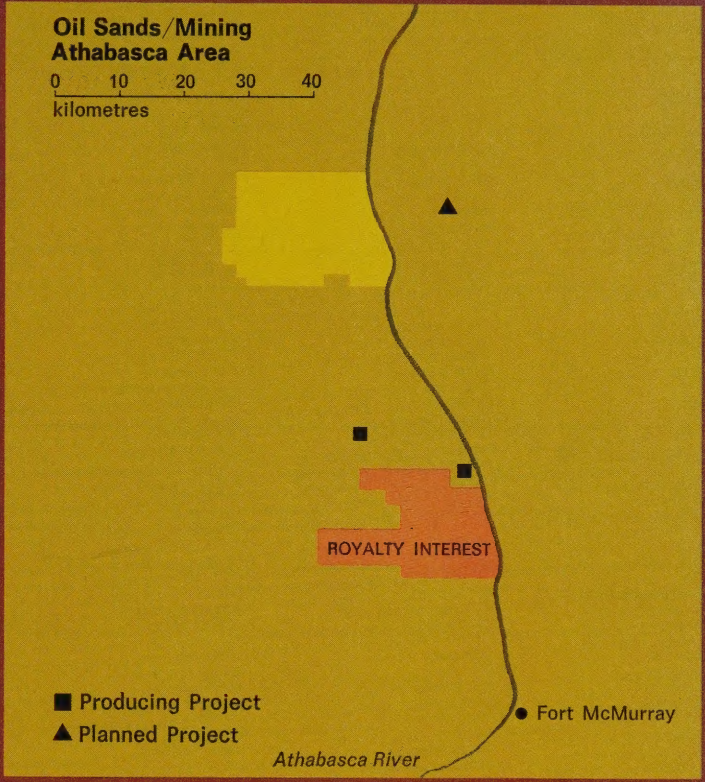
At Grande Prairie, in the northwestern part of the province, BP has interests ranging from 5 to 20 per cent in 75,328 hectares of leases. The Company participated in the drilling of 14 gas wells in this area.

In the Bellis area of east-central Alberta, where BP has interests ranging from 37.5 to 100 per cent in 16,512 hectares, 16 wells were drilled either by the Company or on farmout, resulting in eight gas discoveries, seven of which were on wholly-owned BP lands.

At Bonanza, in the Peace River area of Alberta, five oil wells were drilled in the Boundary

At Marguerite Lake, in the Cold Lake region of northeastern Alberta, BP's pilot plant recovers bitumen from underground oil sands. Maps on the facing page show the Company's areas of interest in the Alberta oil sands.





Major oil sands deposits of Alberta

BP Canada oil sands interests Wabasca area

BP Canada oil sands interests Athabasca area

BP Canada oil sands interests Marguerite Lake area

Gross quantities sold – crude oil and natural gas liquids	1980 (cubic metres per day)	1979 (cubic metres per day)
Alberta		
Redwater	**1,654**	1,013
Pembina	**356**	514
Chauvin	**332**	296
South Sturgeon	**221**	271
Swan Hills	**211**	228
Kaybob	**145**	170
Harmattan	**89**	99
Joarcam	**54**	—
Acheson	**32**	81
Others	**338**	416
Total	**3,432**	3,088
British Columbia		
Beatton River	**74**	103
Others	**9**	8
Total	**83**	111
Saskatchewan		
Dollard	**128**	172
Kenosee	**81**	76
Weyburn	**75**	73
Arlington	**52**	—
Instow	**52**	58
Steelman	**50**	57
Others	**192**	234
Total	**630**	670
Total all areas	**4,145**	3,869

Gross Sales – Natural Gas	1980	1979 (thousands of cubic metres per day)
Alberta		
Edson	**566.6**	740.9
S.E. Alberta (shallow gas)	**208.6**	229.5
Craigend	**142.9**	165.5
Atmore	**136.8**	86.4
Minnehik, Buck Lake	**76.7**	81.1
Bellis	**74.6**	63.9
Calgary	**74.1**	73.8
Redwater	**73.0**	—
Harmattan Elkton	**60.1**	74.2
Kaybob	**53.9**	69.6
Cessford	**51.3**	—
Chauvin	**45.2**	64.1
Others	**613.6**	684.6
	2,177.4	2,333.6
British Columbia	**462.8**	748.3
Saskatchewan	**30.2**	30.7
Total all areas	**2,670.4**	3,112.6

Reserves (gross before royalty)	Oil and natural gas liquids (cubic metres)	Natural gas (million cubic metres)
Proven reserves at December 31, 1979	12,985,080	31,011
Add:		
Discoveries and extensions	324,543	1,982
Net revisions to existing reserves	458,232	(745)
	782,775	1,237
Less:		
Production during 1980	1,514,439	972
Proven reserves at December 31, 1980	**12,253,416**	**31,276**
Location of reserves by province:		
Alberta	10,211,422	20,117
Saskatchewan	1,821,268	106
British Columbia	220,726	11,053

This table does not include the Company's share of natural gas reserves delineated in the Arctic Islands, nor any heavy viscous oil in the Company's various Alberta oil sands properties.

Summary of drilling	Oil	Gas	Dry
Exploratory wells			
Working Interest	0	34	17
Farmout (interest retained)	2	14	8
Development wells			
Working Interest	86	37	17
Farmout (interest retained)	4	4	2

This table excludes 3 water injection wells

Lake zone to follow-up the 10-7-82-11 W6M discovery. One well was drilling in early 1981. BP has a 50 per cent interest in these wells.

At Birch Hills, in the Peace River area, where BP also has a 50 per cent interest, Cindy 5-20-76-1W6, a Precambrian exploratory test, was successfully completed as a Stoddart and Belloy gas well. A second location, Cindy 8-3-77-1 W6M, failed to encounter hydrocarbons and was abandoned. Another company drilled and cased two potential gas wells on lands farmed out by BP.

In southern and central Alberta, the Company drilled or, through farmout, participated in, a number of small oil and gas discoveries and development wells in several areas.

At Chauvin, in east-central Alberta, an active exploration and development program is in progress. During 1980 two exploratory wells resulted in one oil discovery and one abandonment; 25 development wells were also drilled, resulting in 21 oil wells, two gas wells and two abandonments.

In the Central foothills area of Alberta, three wells are currently drilling and one development well at Lovett River was completed as a gas well.
To the north, in the Obed-Hinton area, a drilling program to test deeper formations is in progress.

British Columbia

In the Monkman foothills region of northeastern British

Land summary	December 31, 1980 (gross hectares)	(net hectares)	December 31,1979 (gross hectares)	(net hectares)
Petroleum & natural gas acreage				
Leases				
Arctic Islands	**44,505**	**2,285**	75,155	3,018
Alberta	**1,085,630**	**430,132**	1,094,506	457,648
British Columbia	**317,333**	**140,393**	240,103	109,039
Saskatchewan	**32,303**	**9,376**	31,699	10,282
Northwest Territories	**59,527**	**6,804**	59,527	6,804
	1,539,298	**588,990**	1,500,990	586,791
Reservations & permits				
Alberta	**136,173**	**62,935**	150,690	45,946
British Columbia	**220,610**	**80,717**	323,385	139,322
Northwest Territories	**104,536**	**26,069**	143,670	40,723
Arctic Islands	**1,755,208**	**183,648**	2,691,429	299,715
East Coast	**5,469,152**	**2,472,225**	5,444,880	2,435,325
	7,685,679	**2,825,594**	8,754,054	2,961,031
Major options				
Alberta/British Columbia	**16,137**	**6,764**	34,567	6,763
Total petroleum & natural gas acreage	**9,241,114**	**3,421,348**	10,289,611	3,554,585
Coal	**16,672**	**15,178**	16,672	15,178
Minerals	**487,827**	**340,897**	482,350	325,888
Major option – minerals	**125,076**	**114,670**	103,603	103,603
Grand total	**9,870,689**	**3,892,093**	10,892,236	3,999,254

Columbia, extensive drilling was undertaken in 1980. To the southeast of the Murray River discovery, the Quasar et al Murray b-99-E exploratory well was completed as a potential gas well. BP has earned a 16.25 per cent working interest by paying 20 per cent of the cost.

The exploratory well BP Bullmoose c-14-E (BP 80 per cent) tested only small amounts of gas and was abandoned. The BP Murray d-83-J (BP 25 per cent) stepout well and two exploratory wells – BP North Sukunka c-36-F (BP 100 per cent) and BP Highhat d-78-K (BP 18.75 per cent) – were drilling ahead in March 1981.

The Bullmoose a-43-E well (BP 60 per cent), a stepout drilled 4.5 kilometres to the southeast of Bullmoose d-77-E (the discovery well), was successfully drilled as a gas well, thus extending the limits of the Bullmoose field. The initial test on the well indicated a flow potential of 260,000 cubic metres of gas per day at 14,500 kilopascals flowing pressure.

Further north, near Fort Nelson, BP participated in 11 wells. Significant gas discoveries were made at the CDC Mel d-8-I well (BP 11.72 per cent) which tested at 534,000 cubic metres per day, and the Cairn Tsea b-69-C well (BP 13.75 per cent), which tested at 231,000 cubic metres per day. Other gas discoveries included BP South Dilly a-27-E (BP 25 per cent), Czar August d-64-J (BP 50 per cent), Amoco Dilly a-88-F (BP 25 per cent), and Homestead Gunnel a-73-F (BP 12.5 per cent). The Tooga b-68-E well (BP 75 per cent), drilled on a farmout, reached the top of the Slave Point and was cased ready for deepening and testing. Out of the total program, two wells have been abandoned: Homestead et al Gunnel b-62-C and Shell Lucy a-47-C.

The BP et al North Laprise a-45-B well (BP 50 per cent) was drilled to total depth and gas established in the Halfway formation. Further testing was begun in early 1981.

Frontier Areas

Off the East Coast, some 2,800 kilometres of seismic reflection were completed on the southernmost of the three blocks in which BP, the operator, holds a 45 per cent interest. Initially, a well was planned for 1981 on this block, but in view of the uncertainty created by the National Energy Program and the continued jurisdictional dispute between the federal and Newfoundland governments, drilling for 1981 has been postponed. However, further extensive seismic work will be undertaken in 1981.

In the Arctic Islands, the Panarctic BP AIEG Vesey-Hamilton well was drilled to 2,922 metres, but was abandoned when neither the Jurassic nor the Triassic reservoir showed significant hydrocarbons. The Company had a 15 per cent working interest in this well.

In Cumberland Sound, Aquitaine completed 193 kilometres of seismic work and earned a 5 per cent interest in BP's 197,976 gross hectares of permits, thus reducing BP's interest to 45 per cent.

Oil Sands

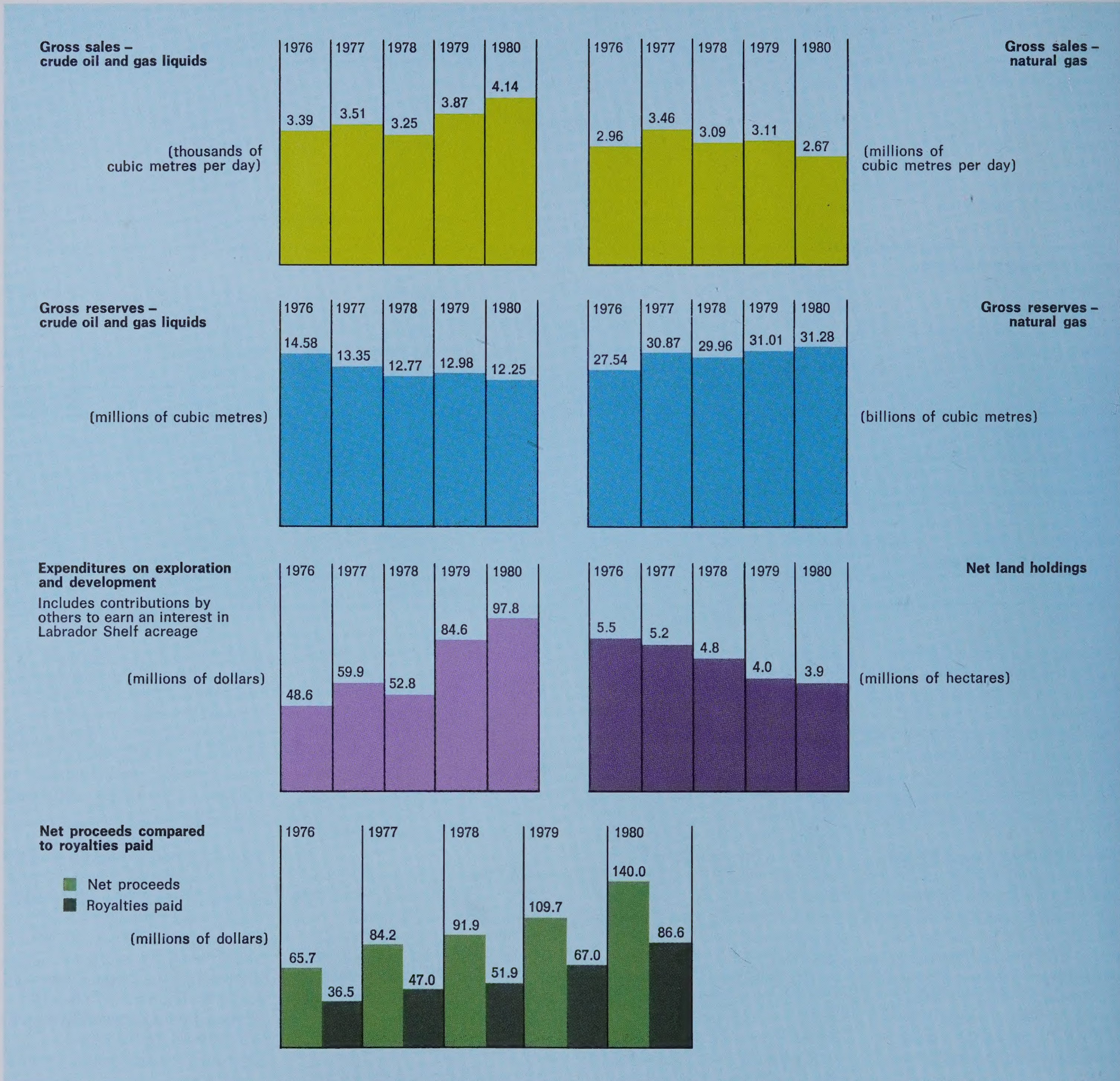
At BP's Marguerite Lake oil sands pilot project, in the Cold Lake region of northeastern Alberta, most of the wells continued to operate on cyclic steam stimulation, with in situ combustion being tried on certain test wells. Testing will continue during 1981, with some infill drilling to be undertaken at the pilot site. In addition, with a view to possible construction of a second plant, wells are being drilled elsewhere on the property better to define the oil sands' character and extent.

At two other oil sands properties, Pelican and Livock, to the northwest of Marguerite Lake, drilling is being undertaken this winter to define the oil sands deposits in the BP hectarage. At Pelican, two wells will be steam tested to determine the productive characteristics of this reservoir.

Coal

At the Company's metallurgical coal property at Sukunka, in northeastern British Columbia, initial engineering of the million-tonnes-per-year mine has been completed. If in the near future a major sales contract is not concluded, the project will be placed on a care and maintenance basis.

Efforts to increase the Company's coal resource base continued. Proven in-place reserves



of metallurgical coal in the Sukunka/Bullmoose area are 182 million tonnes; a further 117 million tonnes of reserves are indicated. To the northwest, where BP has a 100 per cent interest in 16,223 hectares, high-quality thermal coal was found and further drilling is planned in 1981.

The Company has a 100 per cent interest in 24,378 hectares of permits on Vancouver Island. A drilling program for thermal coal was undertaken on this property but met with no success.

Minerals

In 1980, the Company increased its exploration expenditures in the search for uranium and base and precious metals. Uranium exploration proceeded in several areas of the Northwest Territories. Based on the results achieved in 1980 at Hornby Bay (BP 50 per cent) and at Schultz Lake, near Baker Lake (BP 100 per cent), additional drill testing will be undertaken in 1981.

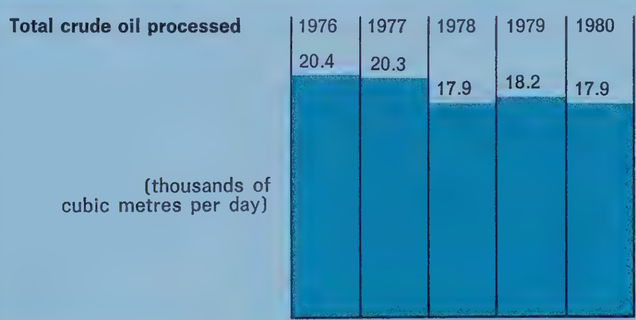
Base metals exploration continued in British Columbia and Manitoba. At the Aylwin joint venture (BP 50 per cent) in southern British Columbia, drilling encountered copper, gold and silver mineralization, and a molybdenum-bearing system was identified. Extensive drilling is planned in 1981.

Massive sulphide-type mineralization was intersected at the Sherridon joint venture in Manitoba (BP 50 per cent), where drilling will continue. New mineral properties have been acquired in British Columbia, Manitoba and Ontario.

A potash exploration permit, covering approximately 10,000 hectares, was acquired near Sussex, New Brunswick, and an initial drilling program of three holes has commenced. BP's interest is 100 per cent.

Supply and Refining

This air preheater, which conserves energy and improves the efficiency of a crude distillation unit at BP's Montreal refinery, was commissioned in October.



Acquiring and delivering sufficient crude oil to meet the needs of BP's two refineries continued to be difficult throughout the year. Volumes received from the Company's main supplier of foreign crude oil again decreased, mainly because of reduced availability from certain Middle East and African countries. The loss of imported crude oil was made good by acquiring additional supplies from Alberta, two cargoes of which had to be delivered to the Montreal refinery by sea from Vancouver, because of a lack of capacity in a section of the Interprovincial pipeline.

Members of the Organization of Petroleum Exporting Countries (OPEC) further increased their prices in January and in May 1980, and again in January 1981. This raised the cost of a barrel of foreign crude oil delivered to eastern Canada in early 1981 to $45, some 40 per cent more than in December 1979. The official selling prices for crude oils sold by the governments of producing countries were exceeded by the prices being paid on the international spot market. Thus, for a period after the outbreak of hostilities between Iraq and Iran, spot cargoes were changing hands at a premium of more than $10 per barrel. By the end of February 1981, as a result of falling demand for crude oil on the international market, this premium had disappeared.

Canadian importers of crude oil and petroleum products continued to receive from the federal government compensation intended to bring the average cost of imports down to that of domestic oil. The price of domestic crude oil rose by $1.00 per barrel on January 1, 1980; by $2.00 per barrel on August 1, 1980; and by a further $1.00 per barrel on January 1, 1981, bringing the wellhead price of Alberta crude oil up to $17.75 per barrel.

The synthetic crude oil levy charged on all crude oils received for processing at Canadian refineries, which stood at 85 cents per barrel on January 1, 1980, had been increased to $2.55 per barrel by November 1, 1980, when it was replaced by the new Petroleum Compensation Charge. This charge was increased to $5.05 per barrel, effective January 1, 1981.

About 64 per cent of the throughput at Montreal Refinery was either domestic or U.S. crude oil obtained in exchange for domestic crude oil. The federal government continued to pay the pipeline transportation cost between Toronto and Montreal until June 30, 1980; since then this pipeline tariff has been paid by the Montreal refiners.

The combined throughput at BP's two refineries in 1980 averaged 17,900 cubic metres per day, or about 75 per cent of capacity, much the same as in the previous year. The crude oil processed included 1,850 cubic metres per day from the United States.

A further $3 million was spent on equipment designed to reduce refinery energy consumption, which since 1973 has been progressively reduced by some 20 per cent. At Trafalgar Refinery, a start was made on a five-year program designed to reduce the noise and odours experienced in residential areas adjacent to the refinery.

BP joined an industry consortium studying the viability of constructing and operating a heavy fuels upgrader designed to serve the Montreal refineries. This plant would convert a proportion of the heavy residual fuel oil into gasolines and middle distillates, and thereby help to bring the product balance at the refinery complex more closely into line with anticipated demand, with a consequent reduction in crude oil imports.

"Service is Back" was the theme of a 1980 promotional campaign, with veteran cars and attendants in 1930s uniforms visiting retail outlets and public exhibitions.

Marketing

A continuing improvement in margins for refined products resulted in a sharply increased contribution to earnings from this sector for the second consecutive year, despite a slight decline in sales volumes.

Total gasoline sales declined marginally as a result of decreased volumes sold to the industrial and commercial markets, a reflection of the generally depressed level of economic activity. The proportion of unleaded gasolines sold continued to rise as older automobiles were scrapped and replaced by newer models. By year end, more than 47 per cent of the gasoline volume sold was unleaded. The volume of retail gasoline sold through self-service facilities remained at between 35 and 40 per cent of the total.

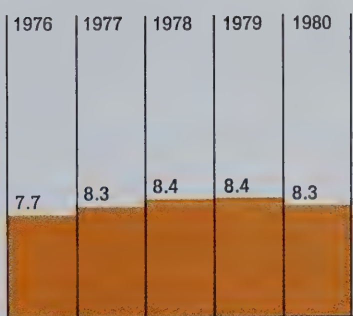
During the year BP continued to develop new retail gasoline outlets, with 14 new high-volume sites being built or leased and a number of new independent dealers joining the BP network.

Diesel sales were slightly higher. The increase was particularly pronounced at retail outlets, where the Company installed additional capacity to meet the growing demand. Sales of aviation fuel declined slightly, but marine fuels and asphalt scored substantial gains. Lower sales of heating oils resulted from a mild first quarter and from conservation efforts by consumers.

The year was marked by two technical advances. Company engineers designed a pneumatically operated guard rail for large delivery vehicles to protect personnel when working on top of the tanks. The design also prevents movement of the vehicle, while the safety rail is raised, by locking the brakes. At Montreal asphalt plant, a computerized blender was installed which automatically controls the blending components as they are loaded into the delivery trucks.

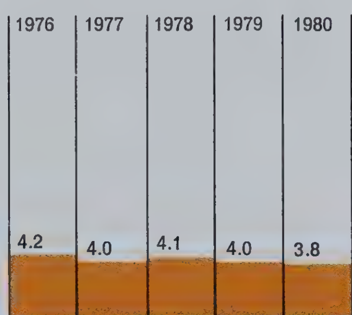
Sales of gasoline

(thousands of cubic metres per day)



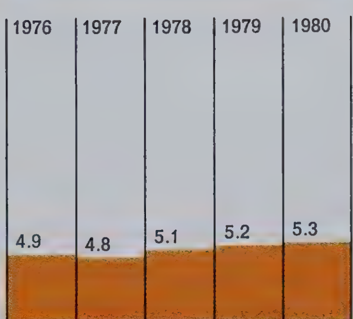
Sales of middle distillates

(thousands of cubic metres per day)



Sales of other products

(thousands of cubic metres per day)



Total sales of petroleum products

(thousands of cubic metres per day)

Corporate Affairs

About to start a second pass in a spraying test of oil-slick dispersant chemicals, an aircraft flies over the area where its droplet patterns are being recorded and evaluated by BP personnel in foreground.

The competition for the BP Canada Energy Research Prize drew 28 entries from 15 Canadian universities. The first prize of $20,000 was awarded to l'Université de Sherbrooke, for Professor Jacques Desnoyers' project studying the use of micro-emulsions to extract crude oil from oil sands.

During the year further improvements were announced to the employees' pension and dental insurance plans, while retirees' pensions were increased in recognition of the continuing rises in the cost of living.

Health records systems were improved and the routine testing of employees' hearing ability was instituted at certain locations.

BP participated with other companies and government agencies in land-based trials to test the effectiveness of dispersants which could be sprayed from aircraft to break up oil slicks. To follow this successful testing, open-sea trials are planned for the summer of 1981.

Francization programs covering the Company's refining and marketing operations in the Province of Quebec were approved by l'Office de la langue française and are being implemented.

The Company doubled the financial support given to educational and cultural institutions and organizations and to health and welfare causes. BP also increased its sponsorship of performances by major symphony orchestras and theatrical and ballet companies.

In co-operation with the Quebec Safety League, the Company sponsored a schoolchildren's safety poster contest which attracted more than 24,000 entries from around the province. This complemented a continuing program in Ontario and Quebec, in which the BP Canada Road Safety Show was presented at more than 500 schools during the year, with a participating audience exceeding 100,000 primary-grade children.

Financial Review

Consolidated net income for 1980 was $104.3 million, or $4.89 per common share, an increase of 55.7% from restated 1979 earnings of $67.0 million.

As indicated in Note 1 to the consolidated financial statements, the Company has changed its accounting to recognize the profit on its own production of crude oil at the wellhead and changed the method of calculating the cost of crude oil in manufactured refined products inventory from average cost for the year to actual cost on a first-in, first-out basis. The net after tax effect of these changes was to increase consolidated net income in 1980 by $.6 million.

The consolidated net income represents a rate of return on average capital employed of 17.33% compared to 13.02% in 1979. Revenue from gross sales and services was $1,258.5 million, an increase of 25.9% compared to $999.4 million in 1979.

Expenses rose by 18.5% to $927.8 million principally as a result of higher costs of purchased crude oil and the impact of inflation on expenses. Federal sales, excise, municipal and other taxes, royalties and provision for income taxes totalled $282.4 million, up 34.9% from 1979; included in this figure are provincial royalties of $82.9 million which increased by 34.0%. Direct taxes on petroleum products collected on behalf of provincial governments amounted to $157.0 million, an increase of $5.4 million over 1979.

Capital expenditure in 1980 including exploration expenditures charged directly to income, was $118.0 million compared to $98.5 million in 1979.

	1980 (millions of $)	1979 (millions of $)
Resource exploration & development	97.8	84.6
Marketing	13.6	7.6
Refining	6.6	6.3
	118.0	98.5

In 1980, repayment of long term debt amounted to $5.4 million, $21.6 million was paid in dividends, $4.2 million was applied on other expenditures, and provision for deferred taxes was $17.3 million.

Funds derived from operations before exploration expenditures amounted to $180.1 million, an increase of $54.8 million from 1979. These funds, together with other cash flow of $13.3 million, were sufficient to finance net capital expenditure, repayment of long term debt, dividend payments and an increase in net working capital of $44.2 million.

The following supplementary information relates to the Company's segments:

		1980 (millions of $)	1979 (millions of $)
Net sales & services	Natural Resources	**$ 140.6**	$110.2
	Refining & Marketing	**1,068.5**	847.9
		1,209.1	958.1
	Less:		
	Own production of crude oil included in sales of refined products	**86.9**	60.8
		$1,122.2	$897.3
Operating profit	Natural Resources	**$ 61.1**	$ 57.7
	Refining & Marketing	**138.1**	63.9
		199.2	121.6
	Net corporate financial revenue (expense)	**3.3**	(.4)
	Income before income taxes	**202.5**	121.2
	Income taxes	**98.2**	54.2
	Net income for the year	**$ 104.3**	$ 67.0
Depreciation, depletion, amortization and dry hole costs	Natural Resources	**$ 26.3**	$ 20.2
	Refining & Marketing	**17.4**	17.1
		$ 43.7	$ 37.3
Identifiable assets	Natural Resources:		
	Oil & gas	**$ 293.3**	$227.2
	Coal mining	**46.0**	42.6
	Refining & Marketing	**540.1**	480.6
	Corporate	**35.8**	29.1
		$ 915.2	$779.5

Current cost accounting information

In periods of rapidly rising prices, historical costs normally used in the determination of financial results are generally considerably less than the current cost of replacing the assets used in producing current revenues. This is particularly true in the oil and gas industry, especially with respect to the value of oil and gas reserves.

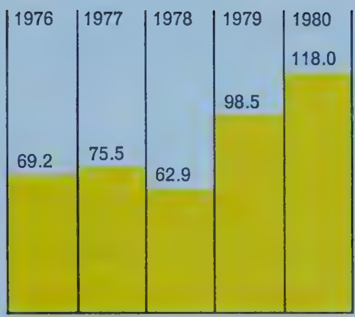
There have been a number of attempts to show more clearly the impact of inflation on business enterprises, most recently the "current cost accounting" proposals of the Canadian Institute of Chartered Accountants. By reducing the income based on historical costs by the amounts needed to maintain the business as a going concern, to arrive at "current cost income", and by allocating some of this additional provision to borrowed capital, the amount of "current cost income attributable to the common shareholders" is determined.

Application of these proposals to the Company's 1980 results would increase cost of sales by $48 million and depreciation and depletion by $75 million. It is estimated that it would also produce a monetary working capital increase of $20 million. These adjustments, however, would, it is estimated, be abated by a financing adjustment of some $33 million, so that the current cost income before income taxes attributable to the common shareholders would be $92 million.

It is, however, important to note that the foregoing does not give recognition to the increase in value of oil and gas reserves which could be very significant. Because the estimation of reserves cannot be an exact process and because of the wide uncertainty surrounding future oil and gas prices, no attempt has been made to estimate the current value of the Company's proven reserves or to calculate the

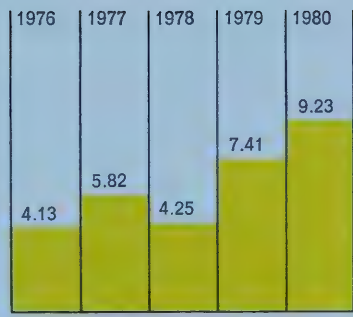
Expenditures on property, plant, equipment and exploration
Includes contributions by others to earn an interest in Labrador Shelf acreage

(millions of dollars)



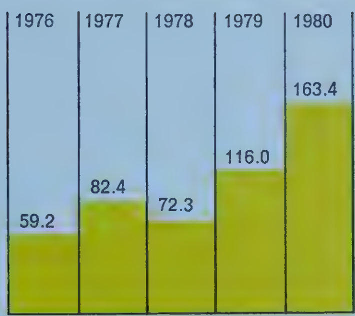
Net income per dollar of net revenue

(cents)



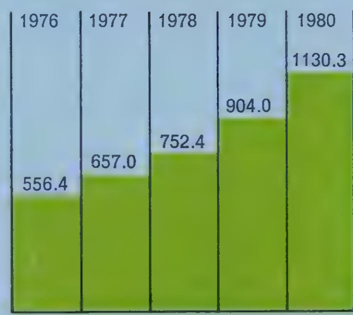
Total funds derived from operations

(millions of dollars)



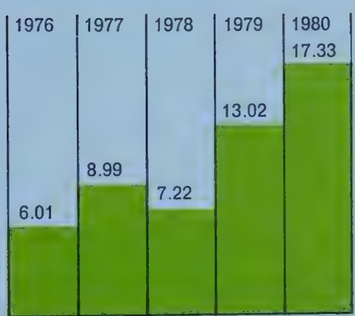
Net revenue

(millions of dollars)



Return on average capital employed

(%)



increase in value during the year. Information as to the volume of reserves is given on page 6.

Note: Definition of current cost adjustments:

1. Cost of sales – to provide for the difference between current prices and those in effect at the time goods are purchased or produced.
2. Depreciation and depletion – to provide for replacement cost of fixed assets greater than their original costs and for finding costs adjusted to current costs.
3. Monetary working capital – to finance net working capital increased as a result of changing prices.

Summary of Accounting Policies

The principal accounting policies of BP Canada Inc. are as follows:

Investment in subsidiary companies

The consolidated financial statements include the accounts of subsidiary companies, all of which are wholly-owned. When a business is purchased, assets including goodwill and liabilities are recorded at their fair values at the date of acquisition and depreciation, depletion and amortization from that date are based on these values.

Property, plant and equipment; depreciation, depletion and amortization

Marketing, refining and production assets

Property, plant and equipment includes the cost of land and facilities, assets under capital leases based on the present value of the future net minimum lease payments and of significant improvements thereto. Generally, depreciation and amortization are provided on assets on a straight line basis over their estimated useful lives which are as follows:

	Number of years		
	Refining	Marketing	Natural Resources
Owned assets:			
Buildings	30 to 50	10 to 20	
Tanks and pipelines	30	10 to 20	25
Equipment	20	10	4 to 12
Automotive equipment	5	5	5
Assets under capital leases:			
Buildings	10 to 20	10 to 20	
Equipment	5 to 10	5 to 10	
Automotive equipment	5	5	

Exploration and development costs

A successful efforts method of accounting is used, whereby the acquisition costs of oil and gas properties, the costs of exploratory wells and the costs of drilling and equipping development wells are capitalized. Acquisition costs are amortized over the period of exploration until such time as they are determined to be productive or judged to be impaired. Exploratory dry hole costs and properties judged to be impaired are charged against income. Unamortized acquisition costs of productive oil and gas properties and costs of successful exploratory drilling and of drilling and equipping development wells are charged against income on the unit of production method. Other exploration expenditures are charged against income.

Property acquisitions and pre-production costs related to coal mining development are capitalized and are to be amortized at the commencement of commercial production. Coal and mineral exploration costs are charged to income in the year incurred.

Inventories

Inventories of crude oil are valued at the lower of cost (which in the case of crude oil from the Company's own production is the market value at the date produced) and net realizable value. Inventories of refined products and merchandise are valued at the lower of cost (including the cost of crude oil determined as indicated above) and net realizable value. Cost is determined on a first-in, first-out basis, which for manufactured refined products is a method adopted in the current year.

Sales and services

In 1980 the Company changed its accounting to recognize the profit on its own production of crude oil at the wellhead. The market value of its own production of crude oil is included in gross sales and services, and the value of the portion of this crude which has been refined and sold is shown as a deduction in arriving at net sales and services.

The Company purchases large volumes of crude oil from other producers and sells to other companies in the oil industry the portion of its own net production and purchases which is not required for its own refineries. The Company's practice is to exclude such transactions from both net sales and services and costs.

Sales and fuel taxes collected for the provincial governments have been excluded from sales and services revenue.

Income taxes

The Company provides for income taxes on the tax allocation basis of accounting under which the provision for income taxes is computed on the basis of income reported in the financial statements rather than that reported in the Company's tax returns. Taxes provided on income deferred for tax purposes by claiming deductions greater than the related charges in the accounts are reflected as deferred income taxes in the consolidated balance sheet.

Foreign currency translation

Amounts in currencies other than Canadian dollars have been translated as follows: Current assets and current liabilities – at the rate of exchange prevailing at the year end; long term debt – at the rate of exchange prevailing at the date the debt was incurred; revenues and expenses – at rates prevailing throughout the year.

Gains and losses resulting from the translation are recognized in the consolidated statement of income.

Report of Management

The Board of Directors is responsible for the financial statements of the Company but has delegated responsibility for their preparation to Management. Management, in fulfilling its responsibilities, has developed and maintained a system of internal accounting controls designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use, and that the financial records are reliable for preparing the financial statements. Management exercises its judgment in determining that a reasonable balance is maintained between the costs of such controls and the benefits to be derived therefrom. The financial statements necessarily include some amounts that are based on Management's best estimates and judgments.

The Board of Directors, through its Audit Committee, is responsible for ensuring that Management fulfils its responsibilities in the preparation of the financial statements.

Each year the shareholders appoint independent auditors to examine and report direct to them on the financial statements. The Audit Committee, which is composed of directors who are not employees of the Company, meets with Management, the internal auditors and the independent auditors to review the audit scope and any recommendations for improvements in the Company's internal controls. The independent auditors, upon completion of their audit, issue a report as to whether the financial statements in their opinion present fairly the financial position and results of operations of the Company in accordance with generally accepted accounting principles applied on a consistent basis.

March 5, 1981

Auditors' Report

To the Shareholders of
BP Canada Inc.

We have examined the consolidated balance sheet of BP Canada Inc. as at December 31, 1980 and the consolidated statements of income, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as at December 31, 1980 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year after giving retroactive effect to the changes in accounting described in note 1.

Clarkson Gordon

Chartered Accountants

Toronto, Canada,
February 20, 1981

Consolidated Statement of Income

for the year ended December 31, 1980

		1980 (thousands of $)	1979 (thousands of $)
Revenue	Gross sales and services	**$1,258,530**	$999,380
	Less:		
	Federal sales taxes	**(49,441)**	(41,272)
	Own production of crude oil included in sales of refined products	**(86,928)**	(60,798)
	Net sales and services	**1,122,161**	897,310
	Income from investments	**8,149**	6,734
		1,130,310	904,044
Expenses	Purchased crude oil, products and merchandise	**650,592**	559,103
	Operating and administrative	**210,833**	171,822
	Depreciation, depletion, amortization and dry hole costs (note 7)	**43,710**	37,312
	Exploration expenditures	**16,737**	9,353
	Interest and discount on long term debt	**5,899**	5,280
		927,771	782,870
Income before income taxes		**202,539**	121,174
Income taxes (note 8):			
Current		**80,947**	41,314
Deferred		**17,288**	12,871
		98,235	54,185
Net income for the year		**$ 104,304**	$ 66,989
Net income per common share (dollars)		**$ 4.89**	$ 3.16

Consolidated Statement of Changes in Financial Position

for the year ended December 31, 1980

		1980 (thousands of $)	1979 (thousands of $)
Funds derived from	Net income for the year	**$104,304**	$ 66,989
	Add (deduct) items not resulting in a flow of funds in the current year:		
	Depreciation, depletion, amortization and dry hole costs	**43,710**	37,312
	Deferred income taxes	**17,288**	12,871
	Profit on redemption of long term debt	**(733)**	(184)
	Other	**(1,214)**	(1,035)
	Total funds derived from operations	**163,355**	115,953
	Add exploration expenditures	**16,737**	9,353
	Funds from operations before exploration expenditures	**180,092**	125,306
	Proceeds on sale of property, plant and equipment	**3,225**	3,691
	Long term borrowing	**9,569**	4,938
	Issues of common shares	**495**	1,921
		193,381	135,856
Funds applied to	Expenditures for property, plant and equipment	**101,227**	89,170
	Exploration expenditures charged directly to income	**16,737**	9,353
		117,964	98,523
	Less: contributed by others (note 2)	**—**	(7,262)
		117,964	91,261
	Repayments of long term debt	**5,364**	6,428
	Cash dividends	**21,602**	13,698
	Redemption of preference shares	**—**	1,175
	Other	**4,249**	1,090
		149,179	113,652
Increase in working capital		**44,202**	22,204
Working capital, beginning of the year		**144,684**	122,480
Working capital, end of the year		**$188,886**	$144,684

Consolidated Statement of Retained Earnings

for the year ended December 31, 1980

		1980 (thousands of $)	1979 (thousands of $)
Balance, beginning of the year	As previously reported	**$221,539**	$172,314
	Add —		
	Cumulative effect of accounting changes (note 1)	**9,404**	5,471
	As restated	**230,943**	177,785
Net income for the year		**104,304**	66,989
		335,247	244,774
Dividends:			
Common shares		**22,404**	13,820
Preference shares		**—**	11
		22,404	13,831
Balance, end of the year		**$312,843**	$230,943

See accompanying notes and summary of accounting policies

Consolidated Balance Sheet

December 31, 1980

BP Canada Inc.

(Continued under the Canada Business Corporations Act)

Assets		1980 (thousands of $)	1979 (thousands of $)
Current	Cash and short term investments, at cost which approximates market	**$ 31,968**	$ 25,420
	Accounts receivable	**182,575**	169,775
	Inventories	**218,738**	160,692
	Prepaid expenses and deposits	**1,782**	3,161
	Total current assets	**435,063**	359,048
Investments and advances	Investments in other companies, at cost	**3,277**	3,310
	Mortgages, loans and other assets	**10,433**	6,377
	Total investments and advances	**13,710**	9,687
Property, plant and equipment	at cost less accumulated depreciation, depletion and amortization (note 2)	**466,478**	410,777
		$915,251	$779,512

Liabilities and Shareholders' Equity		1980 (thousands of $)	1979 (thousands of $)
Current	Accounts payable and accrued liabilities (note 5)	**$179,047**	$168,007
	Income and other taxes payable	**64,730**	44,144
	Current maturities of long term debt	**2,400**	2,213
	Total current liabilities	**246,177**	214,364
Long term debt (note 4)		**71,557**	68,115
Deferred income taxes		**96,006**	78,718
Shareholders' equity	Share capital (note 6)	**188,668**	187,372
	Retained earnings	**312,843**	230,943
		501,511	418,315
		$915,251	$779,512

On behalf of the board:

D. F. Mitchell, Director

M. M. Pennell, Director

See accompanying notes and summary of accounting policies

Notes to Consolidated Financial Statements

December 31, 1980

1. Accounting changes

The Company changed its accounting to recognize the profit on its own production of crude oil at the wellhead. Previously these production profits were eliminated from income and inventory and recognized only when sold as refined products.

In addition, the method of calculating the cost of crude oil in manufactured refined products inventory was changed from average cost for the year to actual cost, on a first-in first-out basis.

Both of these changes have been applied retroactively and have the effect of increasing earnings for 1980 by $614,000 – 3¢ per share (1979 – $3,934,000 – 19¢ per share) and retained earnings at January 1, 1980 by $9,404,000.

2. Property, plant and equipment

	1980			1979
	Investment at cost (thousands of $)	Accumulated depreciation, depletion and amortization (thousands of $)	Net investment (thousands of $)	Net investment (thousands of $)
Natural Resources:				
Oil & gas	**$396,041**	**$160,682***	**$235,359**	$184,085
Coal mining	**45,995**	**—**	**45,995**	42,629
Refining	**194,409**	**104,425**	**89,984**	90,501
Marketing	**174,097**	**82,352**	**91,745**	89,881
Assets under capital leases	**11,455**	**8,060**	**3,395**	3,681
	$821,997	**$355,519**	**$466,478**	$410,777

*Includes depletion of $118,584

Contributions by others for an exploration program on the Company's acreage off the coast of Newfoundland and Labrador have amounted to $38,000,000 of which $7,262,000 was contributed in 1979. These contributions earned a 55% interest in that acreage. In 1980 the costs of exploration on that acreage were borne by the parties in proportion to their respective interests, and only the Company's share has been included in expenditures for property, plant and equipment in the statement of changes in financial position.

3. Sukunka coal project – northeastern British Columbia

In 1977 the Company acquired interests in certain coal licences in northeastern British Columbia for a purchase price of $30,000,000, of which $5,000,000 is payable conditional upon completion of certain railroad and port facilities to be installed by other parties. The Company also has entered into an agreement with BP Canadian Holdings Limited, which owns 64.5% of the issued common shares of the Company, under which BP Canadian Holdings Limited was assigned a 50% working interest in the Company's interest in the property, and undertook to pay one-half of the acquisition and development costs. Under this agreement, the Company will initially contribute 100% of the costs until, after reflecting the timing of payments, it has paid 50% of the total costs of the project. Acquisition and development costs to December 31, 1980 total $45,995,000, of which an amount of $3,365,000 was expended in 1980 on exploration, studies relating to the development of the property and on administrative costs. If no further costs were to be incurred on the project after December 31, 1980, at that date, under the agreement, an estimated amount of $27,000,000 would be due to be contributed by BP Canadian Holdings Limited.

The Company has not yet been successful in obtaining contracts for the sale of coal. However, the Company will continue its endeavours to secure such contracts and if they are obtained early in 1981, construction of the project could start in 1981 with coal available for sale two and a half years after construction commences. Production could be built up to the rate of one million tons per annum of sales within a year after the first sale at a total estimated further capital cost of $153,000,000 in mid-1981 dollars.

If in the near future the Company is not successful in obtaining contracts for a major portion of the planned output, the project will be placed on a care and maintenance basis pending a decision as to its future. Management considers, however, that after taking into account the contribution that would be due from BP Canadian Holdings Limited under the agreement, no adjustment is required to the carrying value of the project at this time.

4. Long term debt

	1980 (thousands of $)	1979 (thousands of $)
BP Canada Inc.:		
6% Sterling loan maturing in 1983 ($2,805,000 at 1980 year-end exchange rate)	**$ 2,437**	$ 3,412
7¾% U.S. dollar Series A debentures, maturing February 15, 1993 ($23,849,000 at 1980 year-end exchange rate)	**19,915**	19,915
8¼% Series B debentures, maturing February 15, 1993	**18,131**	19,040
Subsidiary of BP Canada Inc.:		
BP Oil Limited –		
5¾% sinking fund debentures Series A, maturing October 1, 1986	**12,747**	15,342
Obligations under capital leases	**3,696**	4,086
Mortgage loans payable	**512**	435
Subsidiary of BP Oil Limited:		
BP Exploration Canada Limited – Gas supply contract advances	**16,519**	8,098
	73,957	70,328
Less current maturities included in current liabilities	**2,400**	2,213
	$71,557	$68,115

Total future minimum lease payments under capital leases extending over various periods to 1997 amount to $4,625,000 of which $929,000 represents interest at rates ranging from 6% to 12.75%.

Repayment and sinking fund requirements, excluding obligations under capital leases, during the four years subsequent to December 31, 1981 are as follows:

1982 – $2,159,000
1983 – $3,184,000
1984 – $4,010,000
1985 – $3.996,000

Total future minimum lease payments under operating leases amount to approximately $32,769,000 which is payable as follows:

1981 – $ 4,916,000
1982 – $ 4,484,000
1983 – $ 4,198,000
1984 – $ 3,721,000
1985 – $ 3,428,000
Thereafter – $12,022,000

5. Accounts payable and accrued liabilities

	1980 (thousands of $)	1979 (thousands of $)
Accounts payable and accrued liabilities	**$151,959**	$152,539
Due to affiliated companies for purchase of crude and product	**20,879**	11,342
Dividends payable:		
Parent company	**4,137**	2,755
Others	**2,072**	1,371
	$179,047	$168,007

6. Share capital

		1980 (thousands of $)	1979 (thousands of $)
Authorized			
30,000,000	common shares without nominal or par value		
Issued			
21,357,340.8	common shares (21,296,922.8 in 1979)	**$188,668**	$187,372

During 1980, 18,918 common shares were issued pursuant to the Company's stock dividend option.

At December 31, 1980 options were outstanding to officers and employees to purchase 26,000 common shares at a price of $13.05 exercisable annually to June 19, 1983. During the year options on 41,500 shares were exercised.

7. Depreciation, depletion, amortization and dry hole costs

	1980 (thousands of $)	1979 (thousands of $)
Depreciation	**$21,177**	$19,808
Depletion	**6,700**	6,857
Amortization:		
Assets under capital leases	**1,171**	1,110
Exploration properties	**5,988**	2,812
Dry hole costs	**8,674**	6,725
	$43,710	$37,312

8. Income taxes

Total income tax expense was $98,235,000 in 1980 and $54,185,000 in 1979, effective rates of 48% and 44% on income before income taxes respectively. Such income tax expense varies from the amounts that would be computed by applying the Canadian federal and provincial income tax rate of 49% (47% in 1979) to income before income taxes for the following reasons:

	1980 (thousands of $)	1980 (% of pretax income)	1979 (thousands of $)	1979 (% of pretax income)
Income tax expense calculated at the statutory rate	**$100,299**	**49**	$57,597	47
Increase (decrease) in income taxes resulting from:				
Non-deductible royalties, mineral taxes and expenses	**41,269**	**20**	28,680	23
Federal resource allowance	**(22,886)**	**(11)**	(17,563)	(14)
Provincial rebates	**(5,389)**	**(3)**	(3,891)	(3)
Depletion allowance earned by exploration and development expenditures	**(11,132)**	**(5)**	(8,155)	(7)
Inventory allowance	**(2,240)**	**(1)**	(1,653)	(1)
Other	**(1,686)**	**(1)**	(830)	(1)
Income tax expense	**$ 98,235**	**48**	$54,185	44

Deferred income taxes result from timing differences in recognition of income and expenses for income tax and financial statement purposes. The sources of these differences and the tax effect of each were as follows:

	1980 (thousands of $)	1979 (thousands of $)
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	**$ 4,366**	$ 4,110
Exploration and development expenditures claimed for income tax purposes in excess of depletion	**12,060**	11,751
Other	**862**	(2,990)
	$17,288	$12,871

9. Segmented information

The Company's primary activities are the exploration for and the development of natural resources and the refining and marketing of petroleum products. Segmented financial information is shown in the financial summary on page 14 of the Annual Report.

10. Transactions with related companies

The Company purchases a portion of its crude oil and product requirements from the BP Group of companies. In 1980 such purchases aggregated $141,642,402 (1979 – $90,735,658). The Company also sells refined product to or on behalf of the BP Group. In addition to transactions with its parent company related to the development of its coal interests described in note 3, the Company also has technical service agreements with the BP Group under which it paid $667,717 in 1980 ($559,798 in 1979). Amounts due to related companies at the year-end are detailed in note 5.

11. Pension plans

Based on the latest actuarial valuation of the pension plans as at December 31, 1979 all liabilities were fully funded.

12. Other information

The principal operating subsidiaries of the Company are BP Oil Limited and BP Exploration Canada Limited.

Ten year Operating Summary

	198
Refined product sales	17.
Crude oil processed at refineries	17.
Gross sales of crude oil and natural gas liquids	4.
Gross sales of natural gas (million cubic metres per day)	2.

Ten year Financial Summary

	198
Balance Sheet	
Current assets	$ 435,06
Current liabilities	246,17
Working capital	188,88
Investments and advances	13,71
Property, plant and equipment – net	466,47
Capital employed	669,07
Deduct: Long term debt	71,55
Deferred income taxes	96,00
Shareholders' equity	$ 501,51
Per common share	$ 23.4
Income	
Net revenue	$1,130,31
Expenses	927,77
Income before income taxes	202,53
Income taxes	98,23
Net income for the year before extraordinary items	104,30
Extraordinary items	–
Net income for the year	$ 104,30
Total funds derived from operations	$ 163,35
Per common share	
Net income for the year	$ 4.8
Dividends paid	$ 1.0

1979	1978	1977	1976	1975	1974	1973	1972	1971
(thousands of cubic metres per calendar day unless otherwise stated)								
17.6	17.6	17.1	16.8	16.6	15.4	15.3	15.1	15.0
18.2	17.9	20.3	20.4	19.3	17.0	16.6	15.7	15.8
3.9	3.3	3.5	3.4	3.6	4.5	5.1	4.5	4.1
3.1	3.1	3.5	3.0	2.8	2.9	2.9	2.8	2.5

1979	1978	1977	1976	1975	1974	1973	1972	1971
(thousands of $ except per share amounts)								
$359,048	$280,529	$257,421	$218,969	$222,912	$230,366	$119,704	$ 85,409	$ 79,162
214,364	158,051	143,244	108,208	105,250	131,508	63,313	55,638	61,010
144,684	122,478	114,177	110,761	117,662	98,858	56,391	29,771	18,152
9,687	8,822	8,428	9,980	10,584	15,206	36,385	12,252	14,091
410,777	368,578	355,079	321,148	301,008	292,086	268,860	244,738	251,225
565,148	499,878	477,684	441,889	429,254	406,150	361,636	286,761	283,468
68,115	69,789	75,588	81,951	88,594	99,019	109,105	62,632	70,741
78,718	65,846	60,496	47,096	41,950	32,650	11,929	75	(5,583)
$418,315	$364,243	$341,600	$312,842	$298,710	$274,481	$240,602	$224,054	$218,310
$ 19.64	$ 17.19	$ 16.20	$ 14.83	$ 14.15	$ 13.00	$ 11.38	$ 10.60	$ 10.32
$904,044	$752,422	$656,967	$556,415	$497,384	$415,044	$286,524	$235,423	$227,237
782,870	699,652	587,360	514,078	441,620	345,157	252,610	219,350	215,597
121,174	52,770	69,607	42,337	55,764	69,887	33,914	16,073	11,640
54,185	20,761	31,364	19,365	23,412	30,797	13,156	6,220	3,965
66,989	32,009	38,243	22,972	32,352	39,090	20,758	9,853	7,675
—	—	—	—	—	—	(684)	(576)	4,513
$ 66,989	$ 32,009	$ 38,243	$ 22,972	$ 32,352	$ 39,090	$ 20,074	$ 9,277	$ 12,188
$115,953	$ 72,265	$ 82,399	$ 59,155	$ 70,939	$ 69,231	$ 56,267	$ 37,627	$ 35,681
$ 3.16	$ 1.52	$ 1.82	$ 1.09	$ 1.53	$ 1.86	$ .95	$ .44	$ .58
$ .58	$ .49	$ .44	$ .40	$ .38	$ .24	$ .15	$ .13	$ .03

Board of Directors

R. W. Adam
London, England
A Managing Director,
The British Petroleum Company Limited

Dr. E. W. Best
Calgary
Vice-President,
Natural Resources,
BP Canada Inc.

*P. J. Gillam
London, England
Director
BP International Limited
(formerly BP Trading Limited)

R. W. D. Hanbidge
Toronto
President and
Chief Operating Officer,
BP Canada Inc.

D. F. Mitchell
Toronto
Chairman and
Chief Executive Officer,
BP Canada Inc.

*M. M. Pennell, C.B.E.
London, England

*Charles Perrault
Montreal
President,
Perconsult Limited

*The Hon. M. Sauvé, P.C.
Montreal
Executive Vice-President,
Administrative and
Public Affairs,
Consolidated-Bathurst Inc.

Donald C. Smith
Toronto
Vice-President,
Finance, and Treasurer,
BP Canada Inc.

*G. Meredith Smith
Ottawa

P. I. Walters
London, England
A Deputy Chairman
and a Managing Director,
The British Petroleum Company Limited

P. N. T. Widdrington
London, Ontario
President and
Chief Executive Officer,
John Labatt Limited

*Member of Audit Committee

Officers

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Chairman and Chief Executive Officer

R. W. D. Hanbidge
President and Chief Operating Officer

J. A. Barclay
Vice-President, Supply and Refining

Dr. E. W. Best
Vice-President, Natural Resources

T. R. Dalglish
Vice-President, Marketing

J. Langelier, Q.C.
Vice-President, General Counsel and Secretary

Donald C. Smith
Vice-President, Finance, and Treasurer

K. Healy
Assistant Secretary

J. I. Rawlinson
Assistant Secretary

W. A. Melrose
Assistant Treasurer

F. D. Pynn
Assistant Treasurer

Transfer Agent and Registrar
The Canada Trust Company
Montreal, Toronto, Calgary, Vancouver

Stock Exchange Listings
Montreal, Toronto, Vancouver

Head Office
First Canadian Place
Toronto, Ontario

BP House, Calgary
333 – 5th Avenue S.W.
Calgary, Alberta

BP House, Don Mills
240 Duncan Mill Road
Don Mills, Ontario

BP Minerals
1111 West Hastings Street
Vancouver, British Columbia

25 Adelaide Street East
Toronto, Ontario

Refineries
Montreal Refinery
Ville d'Anjou, Quebec

Trafalgar Refinery
Oakville, Ontario

Sales Offices
Province of Quebec:
Montreal
Quebec City
Sherbrooke

Province of Ontario:
Barrie
Burlington
Cambridge
Chatham
London
Markham
North Bay
Ottawa
Toronto

BP Canada's directors in the board room at First Canadian Place, Toronto. *From left, seated:* R. W. D. Hanbidge, D. F. Mitchell, P. I. Walters, G. Meredith Smith, P. N. T. Widdrington. *Standing:* J. Langelier (secretary to the board), E. W. Best, R. W. Adam, Charles Perrault, The Hon. M. Sauvé, P. J. Gillam, Donald C. Smith, M. M. Pennell.

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